Indiana Utility Regulatory Commission

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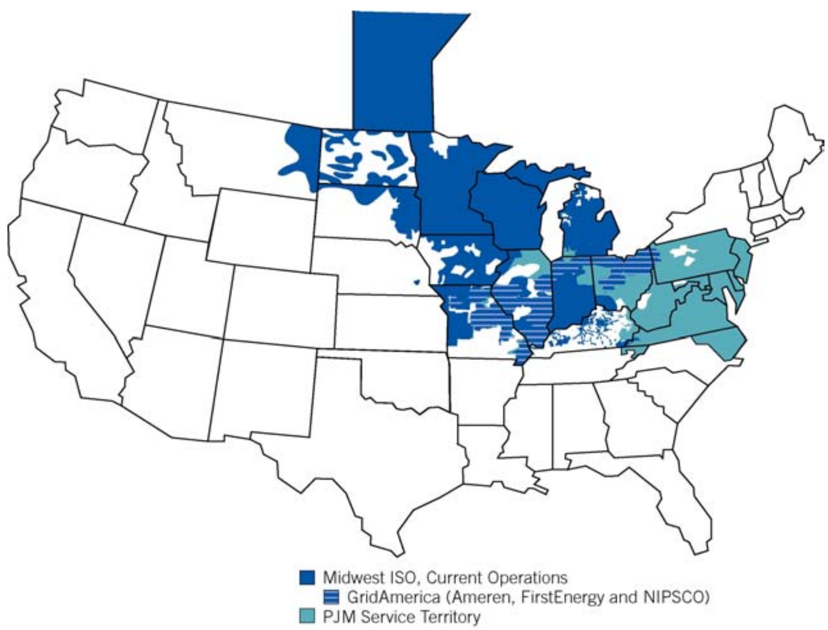
Regional Transmission Grid



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2004
ELECTRIC REPORT
TO THE
REGULATORY FLEXIBILITY
COMMITTEE OF THE
INDIANA GENERAL ASSEMBLY

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PURPOSE AND SCOPE OF REPORT

This report is intended to satisfy the requirements of Ind. Code §8-1-2.5-9(b). The report outlines the status of the Indiana electric utility industry. The report reviews the activities of the electric industry in Indiana and provides an update of facts and developments since the Indiana Utility Regulatory Commission's 2003 Energy Report.

EXECUTIVE SUMMARY AND HIGHLIGHTS

Electricity is a necessity for our economy and quality of life and is often taken for granted by consumers. Five major investor-owned electric companies, 79 municipally-owned and 41 distribution cooperatives supply the electric needs of Hoosiers. The past year has seen continuing developments at both a national and regional level ranging from new environmental regulations, to increased emphasis on improving the reliability of electric service. What follows is a summary of these issues and how Indiana utilities have been affected over the last year.

August 2003 Blackout

On August 14, 2003, large portions of the Midwest and Northeast United States and Ontario, Canada, experienced an electric power blackout. The blackout affected electric load in these states: Ohio, Michigan, Pennsylvania, New York, Vermont, Massachusetts, Connecticut, and New Jersey. On August 15, President George W. Bush and then-Prime Minister Jean Chretien directed that a joint U.S.-Canada Power System Outage Task Force be established to investigate the causes of the blackout and ways to reduce the possibility of future outages. The Task Force issued its final report on April 5, 2004[1]. The report identified the causes of the power outage and why the outage was not confined to a much smaller geographic area. The report also presented technical and policy recommendations to prevent or minimize the likelihood of future blackouts. The Task Force concluded that deficiencies in corporate policies, lack of adherence to industry policies (including the management of vegetation along electric transmission lines), and inadequate management of reactive power and voltage caused the blackout.

Vegetation Management Policies

As part of the blackout investigation, the Federal Energy Regulatory Commission ("FERC") directed a study on the vegetation management policies of the electric utility industry. Vegetation management is the removal of trees and/or other vegetation, or the prevention of vegetative growth, for the purpose of maintaining safe conditions around

[1] The report can be found at: https://reports.energy.gov/.

energized facilities and maintaining reliable electric service. The study report recommended the following to the industry: development of clear and consistent utility vegetation management program expectations and standards regarding utility company performance; development of incentives/penalties for compliance; routine enforcement and oversight; oversight organization support of utility vegetation management activities.

Following the release of the vegetation management report, the FERC issued a data request to all electric utilities to gather information on vegetation management policies. The FERC stated that the data request would provide the FERC, the states, the North American Electric Reliability Council ("NERC"), reliability authorities and the Congress with valuable information regarding vegetation management problems that could cause line outages, and actions taken to alleviate identified vegetation management problems. The FERC would also use this information in cooperation with the National Association of Regulatory Utility Commissioners ("NARUC") Ad-Hoc Committee on Critical Infrastructure to identify appropriate ways to assure effective vegetation management for electric transmission facilities.

Merchant Plants in Indiana

Adequate generation capacity, low wholesale market prices and financial instability have affected the development of new generation capacity constructed, owned and operated by independent power producers. The Commission has not received a new petition for the construction of a merchant plant facility since March 2001. Also, four merchant plant projects have been cancelled and the corresponding certificates of need revoked by the Commission. Only three approved merchant plant projects remain to be completed or cancelled.

Although no new merchant plant projects have been proposed and uncompleted projects may eventually be cancelled, operational merchant plant facilities continue to provide generation capacity to Indiana and the region. Currently, there are approximately 3,626 MWs of generation capacity available from Indiana plant resources. Further, several merchant plant facilities are operated for the direct use of Indiana customers.

Environmental Policy

May 31, 2004 saw the start of the first year of nitrogen oxide ("NOx") reductions required by a rule commonly known as the NOx SIP Call. This regulation requires electric utilities to reduce NOx emissions by approximately 65% during the summer ozone season. This regulation has meant the Indiana electric utilities have had to install costly, capital-intensive pollution control equipment at some of their generating stations.

The US Environmental Protection Agency ("EPA") is developing a new rule to substantially cut mercury emissions from coal-fired power plants. The EPA is due to issue this rule on March 15, 2005. Also in development by the US EPA is the Interstate Air Quality Rule. This rule will substantially reduce sulfur dioxide and NOx emissions (ultimately 70% and 65%, respectively), and its two phases would begin in 2010 and 2015.

Regional Transmission Organizations and Markets

The development of Regional Transmission Organizations ("RTOs") continues. The Midwest Independent Transmission System Operator ("MISO") is preparing to implement a wholesale energy market in its footprint beginning in March, 2005. In addition, under its proposal, the MISO will be responsible for operating the day-ahead and real-time energy markets to arrive at an optimal dispatch for all generation facilities within its region. Indiana MISO members will operate their systems in response to price signals issued by the MISO. In light of the 2003 blackout, and in preparation for the summer of 2004, the MISO completed a number of actions to improve reliability in the Midwest. These actions included the development and implementation of a computer simulation as a primary tool for monitoring reliability, installation of visualization tools and formalized communication protocols for MISO and utility control room operators, enhanced training programs for the MISO and its member utilities, and clarification of command authority between the MISO and its control area member utilities.

Efforts also continued to secure the RTO membership, namely the PJM Interconnection of the American Electric Power Company ("AEP"). The FERC initiated a proceeding in 2003 to accomplish this, and it made a preliminary finding that AEP's voluntary commitment to join PJM was designed to obtain economic utilization of facilities. With a recent approval from the state of Virginia, AEP will become a full member of the PJM by October 1, 2004.

The MISO and PJM, which both operate in Indiana, are working toward creating seamless operations to serve wholesale electricity customers across 22 states and parts of Canada. The IURC is a member of the Organization of MISO States ("OMS"), an organization that coordinates state participation in the stakeholder advisory process for the MISO. Each state retains its existing authorities, but it is anticipated that an improved understanding of regional issues will develop and lead to better decisions, especially with regard to capital investments for transmission expansion.

Merger Authority

The Commission's lack of authority over mergers involving Indiana utilities remains an extremely important issue. This topic has gained even more weight with possible Congressional repeal of the Public Utility Holding Company Act of 1935 ("PUHCA"). If PUHCA is repealed, with the intent of leaving the regulation of holding company mergers to the states, Indiana will be one of the few states left without specific statutory authority over holding company mergers.

Mergers are generally viewed with caution by federal and state regulatory agencies because the merged entity may be able to exercise increased market power resulting in noncompetitive prices, lack of innovation and a decrease in the range and quality of service to the consumer. Mergers can also threaten state commerce by reducing job levels or draining employees and other resources from one state to another. Some mergers, however, result in substantial benefits to the shareholders, customers and employees of the merged companies. All proposed mergers or acquisitions should be objectively analyzed to identify the potential negative and positive outcomes. Indiana needs to participate in a review of the purchases, sales, and transfers of control of its public utilities. Specifically, any review should consider a transfer's effect on:

- Future investment in our communities;
- Employment opportunities and stability for Indiana's workforce;
- Reliability and quality of the utility service; and
- Customer service.

Ratepayers in Indiana could benefit from the IURC having statutory authority to approve, disapprove, or set conditions on mergers and acquisitions by utilities that operate within the state. The IURC is in a better position than most Federal agencies to analyze and evaluate the impacts of mergers involving its native utilities. Indiana should have the authority to review all aspects of a merger and the merging utilities should understand that regulatory action would be taken to ensure that ratepayers would not be in the position of being adversely affected by anticompetitive practices.

Commission Rulemakings

The Commission has initiated two rulemakings involving the electric industry and one that covers all utility sectors. In April, 2004, a rulemaking on net metering was started. Net metering is an arrangement in which customer-owned generation is interconnected with the utility so that energy can flow to and from the distribution grid and the customer is billed only for his net energy consumption.

The proposed rule applies to all Indiana investor-owned electric utilities and directs them to provide the opportunity of net metering to residential customers and K-12 schools. The rule further outlines the terms and conditions governing such interconnections. The basis and intent of the rule is to encourage small-scale renewable energy projects which allow users a measure of energy independence without jeopardizing the safety, energy cost or service quality of others on the interconnected grid.

In June 2004, the Commission started a rulemaking entitled "Outage and Reliability Statistics Reporting." The proposed rule includes clarifications to outage reporting requirements which are currently codified at 170 IAC 4-1-23, and defines the set of standard reliability measurement statistics to be reported by each utility annually. The proposed rule will provide the outage information the Commission requires while also being a more efficient process for the utilities.

In July 2004, the Commission started a rulemaking entitled "Customer Service Rights and Responsibilities Rulemaking." This rule will address such issues as customer deposits to establish utility service, credit worthiness and estimated bills. All three Commission rulemakings are expected to be finalized over the next year.

I. NATIONAL ELECTRIC INDUSTRY ISSUES

A. August 14, 2003 Blackout in the United States and Canada

On August 14, 2003, large portions of the Midwest and Northeast United States and Ontario, Canada, experienced an electric power blackout. The blackout started in the area of northern Ohio served by FirstEnergy, rapidly spreading through a succession of transmission and generation outages which affected an estimated 50 million people and 61,000 megawatts ("MW") of electric load in the states of Ohio, Michigan, Pennsylvania, New York, Vermont, Massachusetts, Connecticut, New Jersey and the Canadian province of Ontario. The blackout began a few minutes after 4:00 PM (EDT), and the power was not fully restored for up to four days in some parts of the U.S. Parts of Ontario suffered from rolling blackouts for more than a week before full electric service was restored.

U.S.-Canada Power System Outage Task Force

On August 15, President George W. Bush and then-Prime Minister Jean Chretien directed that a joint U.S.-Canada Power System Outage Task Force be established to investigate the causes of the blackout and ways to reduce the possibility of future outages. U.S. Secretary of Energy Spencer Abraham and Herb Dhaliwal, Minister of Natural Resources, Canada, chaired the joint Task Force. Three other U.S. representatives and three other Canadian representatives were named to the Task Force. The Task Force created 3 working groups – an Electric System Working Group, a Nuclear Working Group and a Security Working Group. Each working group consisted of state and provincial representatives, federal employees, and contractors working for the U.S. and Canadian government agencies represented on the Task Force.

The Task Force issued its final report on April 5, 2004[2]. The report identified the causes of the power outage and why the outage was not contained within a much smaller geographic area. The report also presented technical and policy recommendations to prevent or minimize the likelihood of future blackouts.

The Task Force concluded that deficiencies in corporate policies, lack of adherence to industry policies, and inadequate management of reactive power and voltage caused the blackout. There were four groups of causes for the blackout:

1. FirstEnergy ("FE") and the East Central Area Reliability Council ("ECAR") failed to assess and understand the inadequacies of FE's system.
2. Inadequate situational awareness at FE. FE did not recognize or understand the deteriorating condition of its system.
3. FE failed to adequately manage tree growth in its transmission rights-of-way.
4. Failure of the interconnected grid's reliability coordinators[3] to provide effective real-time diagnostic support that serves as early warning assessments of power system reliability.

The problems began at 12:15 p.m. (EDT) when inaccurate input data effectively shut down the MISO's information system that monitors the transmission grid. MISO usually runs its state estimator every five minutes in order to provide operators with an up-to-date picture of system developments. But due to human error this portion of the monitoring system was inadvertently turned off. The mistake with the state estimator was not discovered until about 2:40 p.m. by which time FE's Eastlake Unit 5 generator had gone off line.

Starting around 2:14 p.m. (EDT) FE's control room operators lost the alarm function that provided audible and visual indications when a significant piece of equipment changed

[2] The report can be found at: https://reports.energy.gov/.
[3] A reliability coordinator is an organization, such as the MISO, responsible for the safe and reliable operation of the interconnected transmission system for their defined area, in accordance with NERC reliability standards, regional criteria, and subregional criteria and practices. This entity facilitates the sharing of data and information about the status of the transmission system in the area for which it is responsible and coordinates emergency operating procedures.

from an acceptable to a problematic condition. Shortly thereafter, FE's control room computer systems were not operating properly. For over an hour no one in FE's control room realized this. As a result, FE's system operators remained unaware that their electrical system condition was beginning to degrade. Unknowingly, they used the outdated system condition information to discount information from other utilities about growing system problems.

From 3:05 p.m. (EDT) to 3:41 p.m. (EDT), three 345-kV[4] lines failed with power flows at or below each transmission line's emergency rating. Each failure was the result of a contact between a line and a tree that had grown so tall that, over a period of years, it encroached into the required clearance height for the line. As each line failed, its outage increased the loading and decreased voltage on the underlying 138-kV system serving Cleveland and Akron, pushing those lines into overload. At 3:05 p.m. (EDT) the resulting heavy loadings on other circuits lead to the tripping and lock-out of FE's Sammis-Star 345-kV line. This event triggered a cascade of interruptions on the high voltage system. Within seven minutes the blackout spread from the Cleveland and Akron area across much of the northeast U.S. and Canada.

The Task Force also compared the August 14, 2003 blackout with seven previous outages: (1) Northeast blackout on November 9, 1965; (2) New York City blackout on July 13, 1977; (3) West Coast blackout on December 22, 1982; (4) West Coast blackout on July 2-3, 1996; (5) West Coast blackout on August 10, 1996; (6) Ontario and U.S. North Central blackout on June 25, 1998; and (7) Northeast outages and non-outage disturbances in the summer of 1999.

The blackout on August 14, 2003, had several causes or contributory factors in common with the earlier outages:

- ? Inadequate vegetation management;
- ? Failure to ensure operation within secure limits;

[4] Long distance electric transmission lines are typically at voltages of 100kV and higher.

- ? Failure to identify emergency conditions and communicate that status to neighboring utility systems;
- ? Inadequate operator training;
- ? Inadequate regional-scale ability to assess conditions over the power system; and
- ? Inadequate coordination of relays and other protective devices or systems.

Causal features new to the August 14 blackout include: inadequate interregional visibility over the power system; dysfunction of a control area's computer information system; and lack of adequate backup capability to that system.

The Task Force report listed 46 steps that industry, regulators and the North American Electric Reliability Council ("NERC") should take to prevent future failures. The recommendations included the following:

- ? Implementing of mandatory and enforceable electricity reliability standards in both the U.S. and Canada, with penalties for noncompliance, backed by appropriate government oversight;
- ? Strengthening the institutional framework of the NERC and its initiatives on compliance;
- ? Developing a funding mechanism approved by regulators for the NERC and the regional reliability councils, in order to ensure their independence from the parties they oversee;
- ? Addressing deficiencies identified in FirstEnergy and some reliability organizations in the U.S., by June 30, 2004;
- ? Improving near-term and long-term training and certification requirements for operators, reliability coordinators and operator support staff; and
- ? Increasing the physical and cyber security of the transmission network.

Utility Vegetation Management Report

As part of the task force investigation of the August 14 Blackout, CN Utility Consulting, LLC ("CNUC") was commissioned to perform the following tasks:

- Collect and analyze information and data regarding transmission right-of-way vegetation management practices of three utility companies in order to assess the strengths and weaknesses of each utility company's vegetation management program. The utilities were American Electric Power ("AEP"), FirstEnergy and Cinergy.
- Identify generic best practices for transmission-level vegetation management to enhance system performance and transmission reliability.
- Assist in the field investigation and prepare a written Initial Report regarding the August 14th vegetation-related faults on the following circuits:
  - Stuart – Atlanta (345 kV) AEP
  - Star – South Canton (345 kV) FirstEnergy
  - Harding – Chamberlain (345 kV) FirstEnergy
  - Hanna – Juniper (345 kV) FirstEnergy[5]

On March 2, 2004, CNUC issued the Utility Vegetation Management Final Report[6]. The Final Report covered the following topics:

- Background material on the purpose, methods, impediments and funding of utility vegetation management activities to provide an understanding of the report findings;
- A detailed discussion of the field investigation related to the August 14th Outage;
- Assessments of the Utility Vegetation Management ("UVM") programs for AEP, FE and Cinergy;
- Recommendations; and,
- Best Management Practices.

In the detailed discussion of the field investigation of the critical circuits, the report provides a chronology of the faults that occurred on August 14th and observations and

[5] CN Utility Consulting, LLC, "Utility Vegetation Management Final Report", March 2004, p.1.
[6] The Final Report can be accessed from the FERC website at www.ferc.gov/cust-protect/moi/uvm-final-report.pdf.

comments of the field sites. One AEP location[7] and three FirstEnergy sites were investigated. The investigation found evidence that if the vegetation at these locations had been properly managed, the resulting faults would not have occurred and contributed to the blackout.

Included in the field investigation section is a review of the Cinergy Columbus-Bedford line in southern Indiana. The consultants noted that while it did not appear that the fault on this line contributed to the blackout, the vegetation situation provided a good example of the obstacles placed in front of utilities that are attempting to manage vegetation near overhead power lines. The report stated:

> Apparently work on this span had been halted various times by the owner of the property. The owner of the property had severely limited the ability to achieve necessary clearances and to apply herbicides to control future growth. While Cinergy, does, in fact, have documented rights to perform this work (documented easement), this landowner has successfully halted work from proceeding on several occasions. This included the homeowner obtaining a court-granted temporary injunction halting work by Cinergy[8].

In the Assessment section of the Final Report, CNUC presents the results of the UVM program assessments for AEP, FE and Cinergy. CNUC found that all three UVM programs are consistent with programs of other utility companies. There were strengths and weaknesses in each of the three programs, but there was no evidence to suggest that the programs could be considered sub-standard compared to other utilities.

However, CNUC does,

> "…not believe that the 'current' industry requirements and standards are adequate to require utility companies to achieve the level of UVM necessary

[7] American Electric Power (AEP) is a multi-state utility operating in eleven states. The line investigated in this report is located in Ohio and is part of the Columbus Southern Power facilities. Indiana & Michigan Power (I&M), located in north eastern Indiana is also part of AEP. I&M did not experience any contributory transmission problems August 14th.

[8] See CN Utility Consulting, LLC, "Utility Vegetation Management Final Report", p.18.

to improve reliability by reducing tree-caused transmission outages. If compared to the 'best management practices' outlined in Section VII of this report, all three utilities would have sub-standard programs."[9]

The consultants also noted that if 'best management practices' were applied to the rest of the industry, only a handful of utilities would be above sub-standard.

CNUC made the following recommendations to AEP, FE and Cinergy:

- Consider adopting the Best Management Practices as defined in the Final Report;
- Consider adopting the utility-specific recommendations found in the Final Report;
- Work with appropriate officials and the public to remove obstacles to completing the required work in a timely manner;
- Consider performing routine UVM program assessments;
- Work toward developing a Best-In-Class UVM program[10].

CNUC also recommended that each utility consider direct involvement with The National Arbor Day Foundation's Tree Line USA program and the U.S. Environmental Protection Agency's ("EPA") Pesticide Environmental Stewardship Program ("PESP"), both voluntary programs. The report explains that while these programs do not necessarily ensure any improvements in preventing outages, they both require that members focus on correctly managing transmission Right-of-Ways and performing work in a manner that is consistent with industry accepted practices. CNUC believes that Tree Line USA and PESP participation are baseline indicators of a competent UVM program.

The Final Report also offered recommendations for oversight and enforcement of UVM activities. Recommendations included the following:

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[9] See CN Utility Consulting, LLC, "Utility Vegetation Management Final Report", p. 39.
[10] Ibid.

- Development of clear and consistent UVM program expectations and standards regarding utility company performance.
- Development of incentives/penalties for compliance/non-compliance.
- Enforcement and oversight should be routine.
- Oversight organizations need to publicly and politically support UVM activities where appropriate[11].

FERC and NARUC Actions

Following the release of the Final Report, the Federal Energy Regulatory Commission issued a data request order to all transmission owners, operators and controllers located in the lower 48 states[12]. The data request required that the following information be submitted to FERC, relevant state regulatory commissions, the North American Electric Reliability Council and associated regional reliability councils by June 17, 2004:

- Describe in detail the vegetation management practices and standards that the provider uses for vegetation control near designated transmission facilities;
- List those designated facilities under the provider's control;
- Indicate how often the facilities are inspected for vegetation management purposes and indicate when the most recent survey was completed;
- Indicate whether any necessary remediation has been completed as of June 14, 2004; and
- Describe any factors that prevent or unduly delay adequate vegetation management [13].

The order stated that the vegetation management report request would provide the FERC, the States, NERC, reliability authorities and the Congress with valuable information regarding vegetation management problems that could cause line outages, and action

[11] See CN Utility Consulting, LLC, "Utility Vegetation Management Final Report", p.3.
[12] Vegetation Management Reporting Order, Federal Energy Regulatory Commission, Docket No. EL04-52-000, April 19, 2004.
[13] See Vegetation Management Reporting Order, pp. 6-7.

taken to alleviate identified vegetation management problems. The FERC would also use this information in cooperation with the NARUC Ad-Hoc Committee on Critical Infrastructure to identify appropriate ways to assure effective vegetation management for electric transmission facilities.

On June 21 and 22, 2004, the NARUC Ad- Hoc Committee on Critical Infrastructure met under the leadership of IURC Commissioner Judy Ripley to review the responses to FERC's data request.

The IURC received copies of the responses to FERC's data request from Cinergy, Indianapolis Power & Light, American Electric Power, Hoosier Energy, Vectren Energy, Northern Indiana Public Service Company, and Ohio Valley Electric Corporation and Indiana-Kentucky Electric Corporation[14]. The Commission staff reviewed the responses and found no immediate areas of concern.

B. Federal Environmental Policy

Implementation of NOx SIP Call Begins

In the fall of 1998, the U.S. Environmental Protection Agency ("EPA") finalized a rule known as the NO_X SIP Call[15]. On November 8, 2001, the EPA approved the Indiana Department of Environmental Management's ("IDEM") NO_X rule, making the rule federally enforceable under the Clean Air Act. NO_X emissions reductions required by the IDEM NO_X SIP Call were to be achieved by May 31, 2004.[16] To achieve the required levels of NO_X reductions mandated by the NO_X SIP Call, Indiana utilities were required to implement capital-intensive retrofits to their generating facilities, and/or use NOx allowances (either earned by early compliance, or purchased on the open market) to meet

[14] All responses to FERC's requested vegetation management are available through the FERC website at www.ferc.gov Docket No. EL04-52-000, issued April 19, 2004.
[15] On October 27, 1998, the U.S. EPA promulgated final federal rules requiring 22 states and the District of Columbia to submit state implementation plan ("SIP") revisions to reduce the regional transport of ozone. The federal rule focused on reducing NOx emissions in the affected states.
[16] In 2005 and thereafter, the "ozone season" will be from May 1 through September 30.

the reductions. In the various cost recovery filings received by the Commission, all retrofit projects appear to have been completed on schedule. Indiana utilities that have filed environmental compliance plans with the Commission include Indianapolis Power & Light Company ("IPL"), PSI Energy, Inc. ("PSI"), Northern Indiana Public Service Company ("NIPSCO"), Southern Indiana Gas & Electric Company ("SIGECO"), Indiana Municipal Power Agency ("IMPA"), Hoosier Energy Rural Electric Cooperative, Inc., and Wabash Valley Power Association ("WVPA"). Indiana Michigan Power Company has not submitted a compliance plan to the Commission.

Proposed Mercury Rule

On December 15, 2003, the EPA signed its first proposal to substantially cut mercury emissions from coal-fired power plants. The proposal was issued as a result of a Federal Court settlement with the Natural Resources Defense Council over Clean Air Act requirements. The EPA proposed two alternatives for controlling mercury. The first proposal would require power plants to install controls known as "maximum achievable control technology" ("MACT") to reduce emissions by 14 tons per year (approximately 30% of total emissions) beginning in 2008. A second proposal, favored by EPA, would create a market-based "cap and trade" program that, if implemented, would cut emissions of mercury in two phases. Phase two implementation would require reductions of 33 tons of mercury (approximately 70%), but would not take place until 2018.

In May 2004, the EPA pushed back the timeline for issuing the final rule. The public comment period was extended 60 days to June 29, 2004, and the final rule will be issued on March 15, 2005, instead of December 15, 2004. The proposed rule is very controversial, and the final rule is likely to be challenged in the courts once it is issued. Some parties argue for a federal legislative solution in order to provide more certainty for utilities. On June 29, 2004, the Indiana Department of Environmental Management ("IDEM") filed comments on the rule[17]. In part, Commissioner Lori Kaplan commented:

[17] http://www.in.gov/idem/air/comments062904.html

> Indiana continues to believe that multipollutant federal legislation to address emissions of all pollutants of concern from power plants is the most appropriate approach. With legislation, control requirements for ozone, particles, mercury, and regional haze can be established efficiently and in a way that allows the affected industry to plan and coordinate its control programs. A coordinated legislative approach would allow facilities to maximize the co-benefits that can be achieved with the installation of control devices. In the absence of such legislation, IDEM believes that USEPA should move forward with a proposed regulation that is coordinated with (but not limited by) the Interstate Air Quality rule. We strongly urge action at the federal level.[18]

Clean Air Interstate Rule ("CAIR")

On December 17, 2003, the EPA signed the proposed Interstate Air Quality Rule, commonly known as the Clean Air Interstate Rule. This rule would reduce emissions of SO_2 and NOx in 29 eastern states and the District of Columbia in two phases. Emission of SO_2 would be reduced by 3.6 million tons in 2010 (approximately 40% below current levels) and by another 2 million tons per year when the rules are fully implemented (approximately 70% below current levels). NOx emissions would be cut by 1.5 million tons in 2010 and 1.8 million tons in 2015 (approximately 65% below today's levels). IDEM commented on this proposed rule on March 30, 2004.[19]

Under the proposed CAIR, each affected state would be required to revise its state implementation plan to include control measures to meet specific statewide emission reduction requirements. To achieve the required reductions in the most cost effective way, the proposal suggests that states regulate power plants under a cap and trade program similar to the existing Acid Rain Program. Emissions would be permanently capped and could not increase.

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[18] "Commissioner Kaplan's Comments on U.S. EPA Mercury Rule", available at: http://www.in.gov/idem/air/comments062904.html.
[19] http://www.in.gov/idem/air/IAQRenclosure1.pdf

The EPA plans to issue the final CAIR in late 2004. It envisions the CAIR and the mercury rule working together to ease the cost of equipment retrofits on the power industry. Even so, once these two rules are finalized, they no doubt will require significant spending by Indiana utilities to comply with them. Further, although the final form of the rules is uncertain, the certainty of the rules being implemented, coupled with the long lead times for installing pollution control equipment, means that Indiana utilities will be developing plans to comply now. Petitions by IPL and PSI for approval of their initial environmental compliance plans have recently been received by the Commission.

C. Regional Transmission Organizations – Continuing Developments

A regional transmission organization ("RTO") is an independent entity that monitors electric reliability throughout a geographic region and is responsible for coordinating the wholesale electric transmission system in the region. When a utility company joins an RTO it must turn over operational control, but not ownership, of its transmission system to an independent entity. Operational control of the transmission system includes operating a central, bid-based dispatch over the entire region. The dispatch of generation is the principal means by which the system operators manage the transmission grid and keep the grid within the physical limits for safe and reliable operations.

Centralized economic dispatch permits the generation resources throughout the regional transmission system to meet the demand for electricity at the lowest possible production costs. Economies can be gained through load diversity across the broader region, reduced operating costs per unit of output of larger units, and more extensive use of lower cost generation anywhere in the region.

Additional benefits of an RTO include:

? Development of an improved mechanism to better manage congestion in the power system. The mechanism must provide all transmission customers with efficient price signals regarding how best to use the transmission system.

? Development of a transparent regional wholesale power market will expand trading opportunities and help utility companies optimize power purchases and sales.

? Development of a regionally-coordinated planning process for transmission expansion. By evaluating the need across several states, an RTO is able to plan for the region's electric infrastructure in a unified, cost-effective and environmentally responsible manner.

RTOs have been developing in this region of the country for the last few years. The IURC has followed and participated in the process and has reported on these activities in previous reports to the legislature. The following will be a brief summary of RTO developments for the past year.

Midwest Independent Transmission System Operator ("MISO")

The MISO is based in Carmel, Indiana, and monitors electric reliability throughout much of the Midwest in a region that stretches from Pennsylvania to Nebraska and from Tennessee to the Canadian province of Manitoba. In its role as a reliability coordinator, the MISO is responsible for coordinating the reliable operation of the wholesale electric transmission system and ensuring fair access to the grid.

Several Indiana electric utilities are currently in the MISO: PSI, IPL, SIGECO, WVPA, Hoosier Energy and NIPSCO. NIPSCO has joined the MISO through an intermediary, independent transmission company ("ITC"), GridAmerica. GridAmerica will act as an administrative and operations manager between the MISO and NIPSCO. American Transmission Systems Incorporated, a subsidiary of FirstEnergy Corp. and Ameren is also part of GridAmerica. By allowing GridAmerica to manage their transmission operations with MISO, participating utilities hope to reduce their transmission costs.

PJM

AEP, with electric utility operations in Indiana, Kentucky, Ohio, Tennessee, Virginia and West Virginia, is in the process of joining the PJM. In 1998, the PJM became the first fully functioning Independent System Operator ("ISO") and is the country's first fully functioning regional transmission organization. The organization is responsible for the operation and control of the bulk electric power system throughout all or portions of Delaware, Illinois, Maryland, New Jersey, Ohio, Pennsylvania, Virginia, West Virginia and the District of Columbia.

On May 1, 2004, Commonwealth Edison became fully integrated into the PJM when PJM began managing the flow of wholesale electricity over ComEd's 5,000 plus miles of transmission lines and administering open, competitive wholesale electricity markets in Northern Illinois. Until AEP joins the PJM, ComEd has no direct transmission link with the PJM. In the interim, ComEd needs to use AEP's transmission facilities across Indiana in order to move power between itself and PJM. As a result, AEP has a Pathway Agreement with PJM to provide up to 500 MW of firm transmission service between ComEd and PJM. The agreement will expire on the date that transmission service on AEP's transmission system is provided by the PJM.

Status of AEP's Effort to Join PJM

On September 12, 2003, the FERC initiated a proceeding to resolve issues relating to AEP's entry into PJM. In an order approved June 17, 2004, the FERC affirmed an administrative law judge's decision and ruled that under federal law, the FERC may allow AEP to transfer its transmission facilities to PJM's control over the objections of Virginia. Under section 205(a) of the Public Utility Regulatory Policies Act of 1978 ("PURPA"), the FERC said it can exempt utilities from state laws, rules or regulations that prohibit or prevent the voluntary coordination of electric utilities for economic utilization of their facilities. In March 2000, the FERC in Order No. 442 approved the merger of AEP with Central and South West Corporation ("CSW"), on condition that

AEP transfer operational control of its transmission facilities to a FERC-approved RTO.[20] AEP agreed to that condition. Last year, the FERC made a preliminary finding that AEP's voluntary commitment to join PJM was designed to obtain economic utilization of facilities.

In its June 17, 2004 order, the FERC found that the applicable criteria of PURPA section 205(a) were met. The criteria are: (1) AEP's voluntary commitment to join PJM was an economic use of facilities and resources; (2) the laws, rules and regulations of Virginia were preventing AEP from fulfilling both its voluntary 1999 merger commitment and its application to join an RTO under FERC Order No. 2000; and (3) Virginia's laws do not fall within the statute's exception to PURPA's exemption authority.

Recent action by the Virginia State Corporation Commission ("VSCC") appears to have removed the last regulatory hurdle for AEP to join the PJM. On August 30, 2004, the VSCC granted authority to AEP's operating company Appalachian Power Company to transfer functional and operational control of its transmission assets to PJM. This last approval will allow AEP to become a full member of the PJM by October 1, 2004.

[20] On June 29, 1998, the IURC announced an investigation, Cause No. 41210, into the merger between AEP and CSW. The IURC also intervened in the three FERC dockets initiated in connection with the proposed merger. On April 26, 1999, the IURC approved a settlement in Cause No. 41210 in which one of the settlement terms was that AEP participate in a FERC approved transmission organization. Based on this obligation, the IURC has since issued numerous orders that contemplate or direct AEP to participate in a FERC approved RTO. In connection with these orders the IURC has participated in numerous FERC dockets relating to the matters at issue before the IURC, providing to the FERC copies of its orders and requesting that FERC's orders take cognizance of the IURC orders. See IURC, Cause No. 42350, In the Matter of the Commission's Investigation, Pursuant To IC § 8-1-2-58 Into the Status of the Transfer of Functional Control of Transmission Facilities Located in Indiana, by Indiana Michigan Power Company, D/B/A American Electric Power, To a Regional Transmission Organization and for Commission review of the Transfer Pursuant to IC § 8-1-2-83 and Consolidated with Cause No. 42352 In the Matter of the Petition of Indiana Michigan Power Company D/B/A American Electric Power, For Approval, To the Extent Necessary, To Transfer Functional Control of transmission Facilities Located in Indiana, Final Order issued on September 10, 2003. See also Cause Nos. 42032 and 42027 Consolidated, In the Matter of the Joint Petition of Indiana Michigan Power Company, D/B/A American Electric Power, et al, For Approval, To the Extent Necessary, To Transfer Functional Control of Transmission Facilities Located in Indiana to The Alliance Regional Transmission Organization Pursuant to IC § 8-1-2-83, Final Order issued on December 17, 2001.

The Midwest Market Initiative

In December 2002, the MISO announced the Midwest Market Initiative ("MMI"). The MMI involves the formation of real time and day ahead wholesale markets for trading electricity based on hourly locational marginal pricing.

On July 25, 2003, the MISO initially filed with the FERC a transmission and energy markets tariff to implement its energy market design consisting of day-ahead and real-time energy markets. In open MISO stakeholder discussions and the FERC regulatory process, many issues associated with the MISO's proposed market design and implementation were discussed and debated. Based on the discussions, the MISO filed a motion to withdraw the proposed tariff filing from the FERC's review and requested that FERC provide appropriate guidance on the MISO's market design. The FERC granted this request to withdraw the July 25 filing and also provided guidance to the MISO regarding several key policy and energy market design elements.

On March 31, 2004, the MISO filed its new energy markets tariff with the FERC. The filing included the rates, terms and conditions necessary to implement a market platform that features the centralized dispatch of generation resources throughout much of the Midwest. In the filing the MISO requested a December 1, 2004, start date for the energy markets.

Under the proposed functions, the MISO would be responsible for operating the day-ahead and real-time energy markets to arrive at an optimal dispatch for all generation facilities within the region. This is to help the MISO ensure that all load requirements in the region are met reliably and efficiently. Local utilities such as IPL will operate their systems in response to price signals issued by the MISO.

The tariff filing by the MISO also presented the FERC with the critical threshold issue of how to treat approximately 300 grandfathered agreements ("GFAs") currently in force in the MISO region. The MISO defined GFAs as transmission service agreements entered into prior to September 16, 1998, and stated that up to 40,000 megawatts of capacity may be covered by these agreements, which could potentially conflict with the MISO's grid congestion management framework if not handled appropriately.

In an order issued May 26, 2004, the FERC initiated a proceeding to address aspects of the GFAs. The FERC order strongly encourages parties to settle their contracts consistent with the MISO's proposed tariff filing. For parties unable to reach settlement, the FERC set up a 30-day trial-type evidentiary hearing to determine, for each unsettled contract, the following information:

- Who is responsible for the contract?
- Who is responsible for scheduling service?
- What are the sources of the wholesale power?
- What are the sink (delivery) points for the power?
- What is the maximum number of megawatts transmitted for each set of source and sink points?
- What is the appropriate standard for review of contract modifications?

The FERC stated that gathering this additional information would give it the ability to better ensure the GFAs are accommodated in the MISO energy markets and do not harm reliability or third parties interests.

The order also moved the market start date from December 1, 2004, to March 1, 2005. Initial market trials will run from early December through January, with MISO to file a report on the trials at least 45 days prior to the start of market operations.

MISO Actions to Improve Reliability

On July 1, 2004, the MISO notified the NERC that it had completed a variety of recommended actions to improve overall system reliability following last summer's widespread power outage.[21]

[21] See Section I A "August 14, 2003 Blackout in the United States and Canada", of this report.

The actions completed by the MISO include:

- Development and implementation of the state estimator as the primary tool for monitoring reliability as of December 31, 2003. The state estimator is a sophisticated mathematical "what if" simulator that allows operators and engineers to evaluate the health of the power system every few minutes by simulating the grid's response to hypothetical equipment failures.
- Installation of visualization tools that allow control room operators to proactively monitor the system in greater detail and on a wider geographic basis.

? Enhanced training programs for the MISO and the control area utilities it serves; including simulations of potential high-risk situations to ensure coordinated, timely and appropriate responses should such events occur in the future.

? Formalized communication protocols between the MISO and the control rooms of MISO member utility control areas and adjoining reliability coordinators to ensure clear communications during high risk or emergency situations.

? Clarification of command authority between MISO, its control area member utilities, and adjacent reliability coordinators to define responsibilities and accountabilities, and minimize the potential for inaction caused by ambiguous lines of authority.

Joint Operating Agreement Between MISO and PJM

On December 31, 2003, the MISO and PJM executed and filed a Joint Operating Agreement ("JOA") with the FERC. The JOA will provide the MISO and PJM detailed information about each other's operations, giving each organization a broader perspective than each would otherwise have. The JOA also will form the foundation by which the MISO and PJM will create seamless operations to serve wholesale electricity customers across 22 states, the District of Columbia and parts of Canada.

Finalizing the JOA was put on hold during an internal assessment period after the August 14, 2003, power outage. Both organizations used the time to analyze reliability plans and current operational procedures and to develop new coordination requirements. As a result, the agreement now establishes a number of procedures designed to improve coordination of interregional congestion management, operational data exchange, real-time communications, emergency protocols, system planning and market monitoring.

Organization of Midwest ISO States ("OMS")

In November 2002, the state utility commissions in the MISO footprint initiated the formation of the country's first so-called regional state committee, and the OMS filed its articles of incorporation as an Indiana non-profit in May 2003.[22] The MISO has voluntarily agreed to fund the OMS.

The OMS coordinates state participation in the MISO stakeholder advisory process; coordinates state input to FERC when possible; and facilitates the sharing of information and analysis of issues. Each state retains its existing authorities, but it is anticipated that an improved understanding of regional issues will develop and lead to better decisions, especially with regard to capital investments for transmission expansion.

The OMS formulates positions through its work groups that participate in MISO stakeholder meetings and discuss the issues among themselves. The OMS currently has seven working groups: Pricing; Congestion Management and FTR Allocation; Market Monitoring and Market Power; Resource Adequacy and Capacity Markets; Seams Issues; Market Rules and Implementation Timelines; and Transmission Planning and Siting.

Recent activities of the OMS include:

- Filing comments with the FERC on generator interconnection, Docket No. ER04-458-000 on February 27, 2004;
- Submitting comments to the MISO through its advisory process on a draft of MISO's energy market tariff on March 15, 2004;

[22] State utility commission members are Illinois, Indiana, Iowa, Kentucky, Michigan, Minnesota, Missouri, Montana, Nebraska, North Dakota, Ohio, Pennsylvania, South Dakota, and Wisconsin; plus the Canadian province of Manitoba.

? Filing comments with the FERC on MISO's energy market tariff, Docket No. ER04-691-000 on May 7, 2004; and

? Filing comments with the FERC regarding grandfathered transmission agreements, Docket No. ER04-691-000 and EL04-104-000 on June 25, 2004.

II. INDIANA ELECTRIC INDUSTRY DEVELOPMENTS

A. Merchant Plants

Adequate generation capacity and low wholesale market prices have slowed the development of new generation capacity constructed, owned and operated by independent power producers. The Commission has not received a new petition for the construction of a merchant plant facility since March 2001.

The soft wholesale market and the financial crisis of many merchant plant developers have also led to the cancellation of many merchant plant projects. Since the 2003 Regulatory Flexibility Report was issued, four proposed merchant plant projects have been cancelled and the corresponding certificates of need revoked by the Commission.

Table 1: Cancelled Merchant Plant Projects

Proposed Facility	Proposed Capacity	Location	Cause Number
Cogentrix	800 MW	Lawrence Co.	41566
Tenaska	900 MW	Pike Co.	41823
Putnam Energy	500 MW	Putnam Co.	41856
PSEG Morristown	340 MW	Shelby Co.	41867

Three approved merchant plant projects remain to be completed or cancelled. Commission Orders for these projects specify construction and operational deadlines that must be met if the project is to maintain its certificate of need. Table 2 shows the remaining merchant plant projects in Indiana. There has been no construction on any of these projects in the last twelve months.

Table 2: Merchant Plants Pending or Under Construction

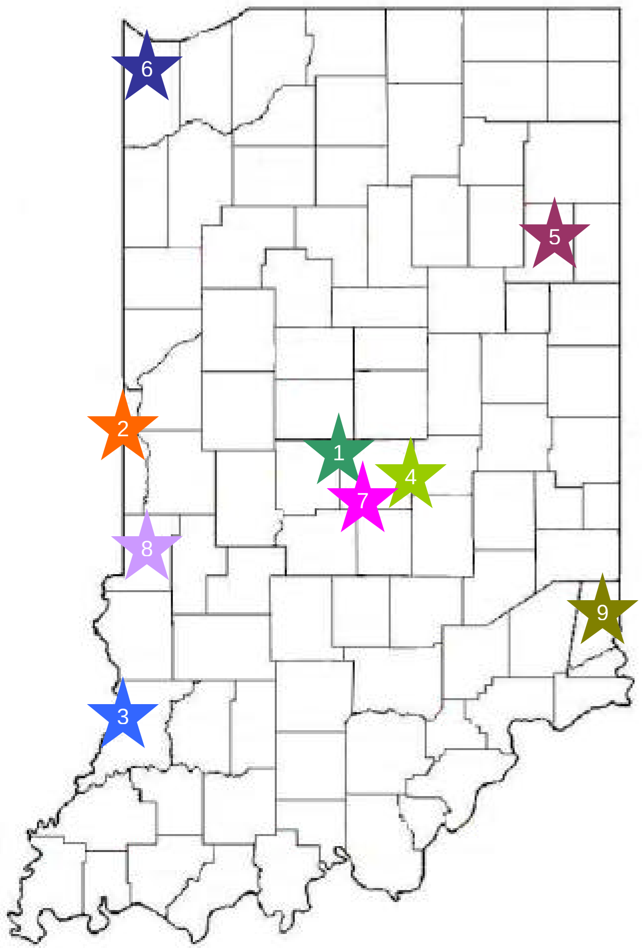
Proposed Facility	Proposed Capacity	Location	Estimated Completion Date	Cause Number
Duke Energy Knox	640 MW	Knox Co.	Undetermined	41803
Hammond Energy	540 MW	Lake Co.	Undetermined	41900
Acadia Bay	630 MW	St. Joseph Co.	Suspended	41966

Although no new merchant plant projects have been proposed and uncompleted projects may eventually be cancelled, operational merchant plant facilities continue to provide generation capacity to Indiana and the region. Currently, there are approximately 3,626 MWs of generation capacity available from Indiana plant resources. Further, several merchant plant facilities are operated for the direct use of Indiana customers.

The Georgetown 1 and the Harding Street Station, owned by Indianapolis Power & Light are both operated and dispatched to serve IPL's native load. Twenty-five percent of the Duke Vermillion facility was recently purchased by Wabash Valley Power Association to meet the needs of its member distribution cooperatives. Duke Vermillion has a total generation capacity of 640 MWs. DTE, located at the same site as IPL's Georgetown 1 and operated by IPL, is part of a package of generation resources that IMPA received approval to purchase in Cause No. 42455. DTE adds 160 MWs to IMPA's generation capacity.

Following is a map that shows the locations of the merchant plant facilities in Indiana.

Merchant Plants Operating in Indiana



1 IPL Georgetown Station (80 MW)—Output from the plant is consumed by IPL customers. The facility began operation in May 2000. (Cause No. 41337)

2 Duke Vermillion (640 MW)—The facility's eight turbines were operational in June 2000 (Cause No. 41388). March 17, 2004, the IURC approved the purchase of a 25% share of the Duke Vermillion facility by Wabash Valley Power Association (Cause No. 42495).

3 Wheatland Generating Facility (500 MW)—Allegheny purchased this facility from Enron in late 2000. The facility's four turbines were operational in June 2000. (Cause No. 41411)

4 DTE Georgetown Station (240 MW)—This plant is located on land owned by IPL. Two turbines were operational in June 2000 (Cause No. 41566). On August 11, 2004, the IURC approved IMPA's purchase of two of the three 80 MW combustion turbine units at the DTE facility in Cause No. 42455.

5 DPL Generating Station (200 MW)—This plant currently has four turbines, which became operational in June 2001. (Cause No. 41685)

6 Whiting Clean Energy (525 MW)—This facility began operation in April 2002 and supplies steam to the adjacent Whiting Refinery. (Cause No. 41530)

7 IPL's Harding Street Station (151 MW)—This facility began operation on May 31, 2002 and is connected to the IPL system. (Cause No. 42033)

8 Sugar Creek (300 MW)—Phase 1 of this facility became operational in August 2002 and is interconnected to both the Cinergy and AEP transmission systems. (Cause Nos. 41753 & 42015).

9 PSEG Lawrenceburg (1150 MW)—This facility became operational in the Summer 2003 and is interconnected to AEP. (Cause No. 41757).

B. The IURC Needs Authority over Mergers and Acquisitions

Ind. Code § 8-1-2-83, which provides for authority over the sale of a public utility's 'franchise, works or system', has seen few changes since its enactment in 1913. It currently provides that, "No public utility, as defined in section 1 of this chapter, shall sell, assign, transfer, lease, or encumber its franchise, works, or system to any other person, partnership, limited liability company, or corporation, or contract for the operation of any part of its works or system by any other person, partnership, limited liability company, or corporation, without the approval of the commission after hearing." That language served the IURC well for years. However, the manner in which companies are bought and sold today, through transfers of stock, is quite different than past transactions.

In 1999, the Indiana Supreme Court ruled that the IURC did not have authority under its statute to review mergers and acquisitions completed through stock transfers. The IURC sought to obtain additional protections for consumers before approving the purchase of Ameritech by SBC and the company appealed that decision to the courts. The IURC had asserted jurisdiction over the transaction by citing the above mentioned code section and determined that "a transaction in which at least 50% of a public utility's voting capital stock is sold, transferred, etc. necessarily constitutes the sale, transfer, etc. of that public utility's franchise, works, or system."

In Justice Boehm's majority opinion on the matter he wrote, "The Commission and others make several compelling policy arguments, all of which boil down to the need for pre-merger investigation and approval by the Commission to protect the consumers of Indiana." He concluded the Court's opinion by stating that, "It may well be that it is more efficient or effective in protecting the interests of the citizens of our state for the Commission to have power to disapprove a shift in control of a utility, rather than simply power to regulate the utility after its ownership is transferred. However, those arguments are for the General Assembly, not this Court or the Commission." Chief Justice Shepard dissented in that case saying, “The executive department has decided to stand its ground in the field of telecommunications. I regret that the judiciary has let it slip away.”

Since the 1999 decision, the IURC has sought to amend its statutory authority to include jurisdiction over such transactions. Each session, the IURC has set forth legislative proposals to close this gap in its authority, without success. During this time, the Commission has lacked jurisdiction over seven large mergers and acquisitions occurring within Indiana, including the SBC-Ameritech and IPL-AES mergers. The Commission has had to address both service quality and financial issues involving IPL since its acquisition by AES. Other recent mergers that have not been reviewed from the uniquely Indiana perspectives are:

- The merger of Bell Atlantic and GTE (the formation of Verizon)
- The merger of Southern Indiana Gas and Electric Company (“SIGECO”) and Indiana Gas (the formation of Vectren)
- NiSource’s purchase of Columbia Energy
- NiSource’s purchase of Bay State Gas
- German energy company RWE’s purchase of Indiana American Water Company

Mergers are generally viewed with caution by federal and state regulatory agencies because the merged entity may be able to exercise increased market power resulting in noncompetitive prices, lack of innovation and a decrease in the range and quality of service to the consumer. Mergers can also threaten state commerce by reducing job levels or draining employees and other resources from one state to another. Some mergers, however, result in substantial benefits to the shareholders, customers and employees of the merged companies. All proposed mergers or acquisitions should be objectively analyzed to identify the potential negative and positive outcomes. Indiana needs to participate in a review of the purchases, sales, and transfers of control of its public utilities. Specifically, any review should consider a transfer’s effect on:

- Future investment in our communities;
- Employment opportunities and stability for Indiana’s workforce;
- Reliability and quality of the utility service; and

- Customer service.

The Indiana Commission, unlike other state commissions, has been unable to negotiate benefits for Indiana customers in return for approving mergers. In Illinois, customers of Ameritech Illinois each received checks for $50 from SBC after the merger, representing the savings of the merger to the company. Indiana customers received nothing. In the purchase of affiliated water companies in Kentucky and Indiana, the Kentucky Commission, with broad merger authority, was able to obtain a rate decrease for Kentucky customers while the IURC, without broad merger authority, did not obtain a rate decrease, but only succeeded in obtaining new reporting requirements, such as that the company's annual reports must be filed in English for the next five years.

An additional concern is Congress' consideration of the repeal of the Public Utility Holding Company Act of 1935 ("PUHCA") in the Energy Policy Act of 2004. A provision repealing PUHCA is included in H.R. 4503, which had passed the House and was received by the Senate on June 17, 2004. If PUHCA is repealed, with the intent of leaving the regulation of holding company mergers to the states – Indiana will be one of the few states left in the cold because of its lack of specific statutory authority over mergers. In fact, all of Indiana's neighboring states have broad merger authority that enables them to protect utility ratepayers.

The Edison Electric Institute, a trade organization of investor-owned utilities, published an article in March 2003 in favor of repealing PUHCA[23]. In it, the group argued "under traditional regulation, FERC and state commissions will regulate electric rates, ensuring that electric consumers do not pay for any of the costs not necessary for providing energy services. FERC and state commissions also will have the authority to prevent any cross-subsidies between a utility and its affiliates. <u>Utility mergers and acquisitions will still require state commission approvals</u> and review by the Department of Justice and the

[23] "Remove Federal Barriers to Competition: Repeal the Public Holding Company Act", March 2003, Edison Electric Institute.

Federal Trade Commission under the antitrust laws"[24] (emphasis added). The repeal of PUHCA is being promoted as eliminating a redundancy because most states have authority to review mergers and acquisitions. This redundancy is only true if a state has the authority to review mergers and acquisitions involving holding companies and stock transfers. Unfortunately, due to the 1999 Indiana Supreme Court ruling, Indiana is now one of the few states without broad merger authority.

While antitrust authorities, such as the Federal Trade Commission or Department of Justice at the federal level, have certain authorities over mergers, they have a national perspective and generally do not consider state specific concerns. The Attorney General on the state level might also have some authorities regarding the policing of mergers and acquisitions. The IURC believes it needs the definitive authority to determine if a merger or acquisition is in the public interest. The IURC is a designated expert in utility operations and pricing of services and thus can determine more accurately the detrimental effects of any merger or acquisition. Furthermore, state commissions are charged with ensuring the public interest is served, which is broader than traditional antitrust theory. For example, antitrust authorities are rarely worried about the role that merger savings have on the overall rates of the utility.

Ratepayers in Indiana could benefit from the IURC having statutory authority to approve, disapprove, or set forth conditions on mergers and acquisitions by utilities that operate within the state. The IURC is in a better position than most Federal agencies to analyze and evaluate the impacts of mergers involving its native utilities. Indiana should have the authority to review all aspects of a merger and the merging utilities should understand that regulatory action would be taken to ensure that ratepayers would not be in the position of being adversely affected by anticompetitive practices.

[24] Ibid.

C. IURC Rulemakings and Other Related Activities

The administrative rulemakings discussed below proceed as outlined in Ind. Code § 4-22-2. This formal process includes public notification and a hearing followed by a period in which the public may submit written comments for consideration. Commission administrative rules differ from Statutes in that they apply only to those entities under Commission jurisdiction.

Net Metering

Net Metering Rulemaking (RM# 03-05)

Following an informal investigation of distributed resources in 2002, the Commission embarked on an effort to encourage each investor-owned utility to voluntarily file a net metering tariff. Net metering is an arrangement in which customer-owned generation is interconnected with the utility so that energy can flow to and from the distribution grid and the customer is billed only for his net energy consumption. PSI, IPL and SIGECO have received approval of net metering tariffs. Additionally, AEP recently filed for approval of its proposed tariff.

Concurrently the Commission staff began drafting a rule addressing net metering. A draft rule was circulated to interested parties on June 16, 2003. The Commission subsequently published a proposed rule in the April 1, 2004, Indiana Register. Feedback on the proposed rule was provided via a public hearing on May 20, 2004, initial comments received by June 11, 2004, and reply comments received by June 25, 2004.

The proposed rule applies to all Indiana investor-owned electric utilities and directs each to provide the opportunity of net metering to residential customers and K-12 schools. The rule further outlines the terms and conditions under which this opportunity must be offered. The rule is intended to encourage small-scale renewable energy projects, allowing users a measure of energy independence without jeopardizing the safety, energy cost or service quality of others on the interconnected grid.

Commission Workshop on HB1212

The Indiana General Assembly considered net metering legislation during its 2004 session as HB1212. The House passed legislation that included elements different than those in the above mentioned proposed rule. The primary differences were the inclusion of larger generating facilities, and the inclusion of commercial and industrial customers. The Commission’s proposed rule includes school and residential customer net metering facilities up to 10 kW capacity, and limits the utility-specific saturation to 0.1% of peak summer demand, while HB1212 includes net metering facilities up to 2 MW capacity and utility-specific saturation of 1% of peak summer demand. The Commission held a workshop on July 8, 2004, to offer an opportunity for an informal exchange of ideas and to consider implications of the differences between the proposed rule and the House legislation. Several discussion threads unfolded; including: participant subsidies, utility lost revenue and modification of existing Commission rules. The Commission has scheduled a second workshop for October, 2004. Prior to this workshop the Commission will circulate a “strawman” proposal for the interconnection of distributed generation resources. It is the Commission’s hope that this proposal will be a substantial first step toward interconnection rules.

Electric Service Quality and Reliability

As a result of a series of public workshops focusing on electric utility service and reliability the Commission has initiated a formal rulemaking in the area of Outage and Reliability Statistics Reporting and an investigation of service area mapping alternatives.

Outage and Reliability Statistics Reporting Rulemaking (RM# 04-01)

The Commission published its proposed rule in the June 1, 2004, Indiana Register. A public hearing was held on July 14, 2004. The proposed rule includes clarifications to each utility's outage reporting requirements currently codified at 170 IAC 4-1-23 and defines the set of standard reliability measurement statistics to be reported by each utility annually.

The Commission utilized the workshop process to critique proposed outage reporting guidelines in a timely and interactive fashion. The proposed rule will provide the outage information the Commission requires, in a manner which can easily be accepted by the utilities.

The informal workshops also led to the development of common definitions which will apply to the reliability measurements which are included in the proposed rulemaking. The proposed statistics reporting will provide information on the frequency and duration of service interruptions experienced by each utility's customers, and will provide the data required by the Commission to proactively monitor the quality of service to Indiana ratepayers.

Service Area Mapping Alternatives

The service quality workshops provided a forum for the Commission to explore alternatives to the present service area mapping archive. Currently the Commission utilizes a manual process based on pen and ink changes to the original mylar maps created in the early 1980's. Technology advances provide more detailed, robust and user-friendly alternatives for consideration. The workshop participants brought their technical expertise to the discussion and provided a range of options which included computer-based mapping using Geographic Information Systems ("GIS") technology. The time and technology are ripe for conversion and the Commission is actively exploring the options for synergies among the various non-electric utilities and the active programs already underway throughout Indiana.

Customer Service Rights and Responsibilities Rulemaking (RM# 04-02)

On July 21, 2004, the Commission initiated a cross-industry rulemaking addressing customer service rights and responsibilities. This rule will address customer deposits to establish utility service, credit worthiness and estimated bills. The rule is designed to establish consistent standards for customer rights and responsibilities across all utility sectors (natural gas, water, sewer, electricity and telecommunications) where possible. A public hearing on this proposed rule is set for September 22, 2004.

III. INDIANA’S ELECTRIC INDUSTRY - STATISTICS

This section is a review of the energy sales, revenue, average price and market share for Indiana’s electric utilities.

Investor-Owned Utilities

There are five investor-owned utilities operating in Indiana. These utilities are the most significant in terms of generation and in number of customers served. The five investor-owned utilities that operate within the state are:

- Indianapolis Power & Light, a wholly-owned subsidiary of AES Corporation;
- Indiana Michigan Power, wholly owned by American Electric Power;
- Northern Indiana Public Service Company, a NiSource company;
- PSI Energy, a wholly-owned subsidiary of Cinergy Corporation; and,
- Southern Indiana Gas & Electric Company, a subsidiary of Vectren Energy Delivery of Indiana.

Municipal Utilities

There are 79 municipally owned electric utilities in Indiana. As of July 2004, twenty-two remain under IURC jurisdiction for rate regulation. Many municipals in the state are members of the Indiana Municipal Power Agency. IMPA was created by a group of municipalities in 1980 to jointly finance and operate generation and transmission facilities and purchase power.

IMPA owns generating facilities and has member-dedicated generation. It also holds ownership interest in Gibson 5 (co-owned with PSI and Wabash Valley Power Association) and Trimble County 1 (co-owned with Louisville Gas and Electric and the Illinois Municipal Electric Agency), and has recently purchased a portion of the DTE Georgetown facility which is operated by IPL. IMPA currently meets the rest of its members' needs through purchased power. IMPA has also received Commission approval to purchase ownership interests in approximately 400 MW of additional generation capacity that is yet unbuilt.

Cooperatives

There are forty-one electric distribution co-ops operating in Indiana. As of July 2004, four co-ops remain under Commission jurisdiction for rate regulation. Most of the distribution co-ops are members of either Hoosier Energy or Wabash Valley Power Association. These two organizations are generating and transmission cooperatives formed to supply power to distribution co-ops. Hoosier Energy and WVPA serve as coordinators of bulk power supplies and transmission services for their members.

Sales, Revenues and Market Share for Electric Utilities

2003 Summary

MWH

Utility	Residential	Commercial	Industrial	Other	Total
Investor Owned Utilities	23,243,091	18,402,344	37,760,777	1,019,404	80,425,616
Rural Electric Membership Corporations	1,041,138	870,149		5,197	1,916,484
Municipal Utilities	1,537,164	3,496,040		694,395	5,727,599
Totals	**25,821,393**	**22,768,533**	**37,760,777**	**1,718,996**	**88,069,699**

REVENUE (000s)

Utility	Residential	Commercial	Industrial	Other	Total
Investor Owned Utilities	$ 1,608,654	$ 1,122,451	$ 1,554,191	$ 73,053	$ 4,358,349
Rural Electric Membership Corporations	74,396	40,368		1,762	116,527
Municipal Utilities	91,553	171,396		29,403	292,352
Totals	**$ 1,774,603**	**$ 1,334,215**	**$ 1,554,191**	**$ 104,218**	**$ 4,767,227**

RETAIL MARKET SHARE BY MWH

Utility	Residential	Commercial	Industrial	Other	Total
Investor Owned Utilities	90.01%	80.82%	100.00%	59.30%	91.32%
Rural Electric Membership Corporations	4.03%	3.82%		0.30%	2.18%
Municipal Utilities	5.95%	15.35%		40.40%	6.50%

RETAIL MARKET SHARE BY REVENUES

Utility	Residential	Commercial	Industrial	Other	Total
Investor Owned Utilities	90.65%	84.13%	100.00%	70.10%	91.42%
Rural Electric Membership Corporations	4.19%	3.03%	0.00%	1.69%	2.44%
Municipal Utilities	5.16%	12.85%	0.00%	28.21%	6.13%

Please note that REMCs and municipal utilities do not present separate commercial and industrial information in the annual reports they submit to the Commission, therefore the summarized commercial and industrial data is shown under the “Commercial” heading on the tables.

Investor-Owned Electric Utilities

2003 Data

MWH

Utility	Residential	Commercial	Industrial	Other	Total
Indiana Michigan Power Company	5,476,309	4,777,223	7,878,082	79,846	18,211,460
Indianapolis Power & Light Company	4,916,519	1,985,618	7,370,326	83,275	14,355,738
Northern Indiana Public Service Company	3,122,471	3,579,726	8,972,159	141,561	15,815,917
PSI Energy, Inc.	8,286,086	6,637,650	11,393,325	697,512	27,014,573
Southern Indiana Gas & Electric Company	1,441,706	1,422,127	2,146,885	17,210	5,027,928
Totals	**23,243,091**	**18,402,344**	**37,760,777**	**1,019,404**	**80,425,616**

REVENUE (000s)

Utility	Residential	Commercial	Industrial	Other	Total
Indiana Michigan Power Company	$ 352,710	$ 272,319	$ 319,783	$ 6,154	$ 950,966
Indianapolis Power & Light Company	300,735	129,790	336,136	11,022	777,683
Northern Indiana Public Service Company	294,901	289,839	380,150	14,386	979,276
PSI Energy, Inc.	554,502	347,796	424,255	39,324	1,365,877
Southern Indiana Gas & Electric Company	105,806	82,707	93,867	2,167	284,547
Totals	**$ 1,608,654**	**$ 1,122,451**	**$ 1,554,191**	**$ 73,053**	**$ 4,358,349**

AVERAGE RATE PER KWH

Utility	Residential	Commercial	Industrial	Other	Total
Indiana Michigan Power Company	$0.06	$0.06	$0.04	$0.08	$0.05
Indianapolis Power & Light Company	$0.06	$0.07	$0.05	$0.13	$0.05
Northern Indiana Public Service Company	$0.09	$0.08	$0.04	$0.10	$0.06
PSI Energy, Inc.	$0.07	$0.05	$0.04	$0.06	$0.05
Southern Indiana Gas & Electric Company	$0.07	$0.06	$0.04	$0.13	$0.06

RETAIL MARKET SHARE

Utility	Residential	Commercial	Industrial	Other	Total
Indiana Michigan Power Company	37.09%	28.64%	33.63%	0.65%	100%
Indianapolis Power & Light Company	38.67%	16.69%	43.22%	1.42%	100%
Northern Indiana Public Service Company	30.11%	29.60%	38.82%	1.47%	100%
PSI Energy, Inc.	40.60%	25.46%	31.06%	2.88%	100%
Southern Indiana Gas & Electric Company	37.18%	29.07%	32.99%	0.76%	100%

Rural Electric Membership Corporations

2003 Data

MWH

Utility	Residential	Commercial & Industrial	Other	Total
Harrison County R.E.M.C.	315,971	195,913	3,028	514,912
Jackson County R.E.M.C.	368,719	73,942	74	442,735
Marshall County R.E.M.C.	69,504	15,869	1,045	86,418
Northeastern R.E.M.C.	286,944	584,425	1,050	872,419
Totals	**1,041,138**	**870,149**	**5,197**	**1,916,484**

REVENUE (000s)

Utility	Residential	Commercial & Industrial	Other	Total
Harrison County R.E.M.C.	$21,139	$9,510	$796	$31,445
Jackson County R.E.M.C.	25,949	4,467	576	30,993
Marshall County R.E.M.C.	6,420	1,333	212	7,965
Northeastern R.E.M.C.	20,888	25,058	178	46,124
Totals	**$74,396**	**$40,368**	**$1,762**	**$116,527**

AVERAGE REVENUE PER KWH

Utility	Residential	Commercial & Industrial	Other	Total
Harrison County R.E.M.C.	$0.07	$0.05	$0.26	$0.06
Jackson County R.E.M.C.	$0.07	$0.06		$0.07
Marshall County R.E.M.C.	$0.09	$0.08	$0.20	$0.09
Northeastern R.E.M.C.	$0.07	$0.04	$0.17	$0.05

RETAIL MARKET SHARE

Utility	Residential	Commercial & Industrial	Other
Harrison County R.E.M.C.	67.23%	30.24%	2.53%
Jackson County R.E.M.C.	83.73%	14.41%	1.86%
Marshall County R.E.M.C.	80.60%	16.74%	2.66%
Northeastern R.E.M.C.	45.29%	54.33%	0.39%

Municipal Electric Utilities

2003 Data

MWH

Utility	Residential	Commercial & Industrial	Other	Total
Anderson Municipal Light & Power	319,612	380,130	4,696	704,438
Auburn Municipal Electric	66,221	450,662	NA	516,884
Bargersville Municipal Power & Light	29,480	15,934	1,872	47,285
Columbia City Municipal Electric	35,216	68,390	3,772	107,378
Crawfordsville Municipal Electric Light & Power	77,595	320,565	22,416	420,576
Edinburgh Municipal Electric	22,092	69,529	1,193	92,814
Frankfort City Light & Power	74,364	262,974	2,749	340,086
Garrett Municipal Electric	58,800	0	0	58,800
Kingsford Heights Municipal Electric	5,645	0	0	5,645
Knightstown Municipal Electric	12,963	10,469	0	23,433
Lawrenceburg Municipal Electric	27,233	104,818	1,568	133,619
Lebanon Municipal Electric	64,749	131,887	3,031	199,667
Logansport Municipal Electric	99,828	280,823	2,812	383,464
Mishawaka Municipal Electric	176,480	373,254	27,070	576,804
Paoli Municipal Electric	38,462	0	0	38,462
Peru Municipal Electric Light & Power	94,977	141,596	4,371	240,944
Richmond Municipal Power & Light	200,399	734,535	608,901	1,543,835
South Whitley Municipal Electric	20,315	0	0	20,315
Straughn Municipal Electric	1,578	0	0	1,578
Tipton Municipal Electric	36,633	71,110	765	108,508
Troy Municipal Electric	8,200	0	0	8,200
Washington City Municipal Light & Power	66,322	79,364	9,179	154,865
Totals	**1,537,164**	**3,496,040**	**694,395**	**5,727,599**

REVENUE (000s)

Utility	Residential	Commercial & Industrial	Other	Total
Anderson Municipal Light & Power	$ 20,346	$ 19,860	$ 942	$ 41,148
Auburn Municipal Electric	2,652	21,015	494	24,161
Bargersville Municipal Power & Light	1,911	1,008	197	3,116
Columbia City Municipal Electric	2,211	3,968	340	6,519
Crawfordsville Municipal Electric Light & Power	5,107	15,143	2,249	22,499
Edinburgh Municipal Electric	1,253	3,581	81	4,915
Frankfort City Light & Power	4,330	10,909	221	15,460
Garrett Municipal Electric	4,817	0	0	4,817
Kingsford Heights Municipal Electric	267	117	72	456
Knightstown Municipal Electric	733	590	64	1,387
Lawrenceburg Municipal Electric	1,491	5,096	191	6,778
Lebanon Municipal Electric	3,806	6,409	317	10,532
Logansport Municipal Electric	6,283	13,824	317	20,424
Mishawaka Municipal Electric	11,417	20,764	2,384	34,565
Paoli Municipal Electric	891	1,420	162	2,473
Peru Municipal Electric Light & Power	5,501	6,743	237	12,481
Richmond Municipal Power & Light	11,788	32,709	20,108	64,605
South Whitley Municipal Electric	534	573	105	1,212
Straughn Municipal Electric	82	5	13	100
Tipton Municipal Electric	2,047	3,520	95	5,662
Troy Municipal Electric	252	383	31	666
Washington City Municipal Light & Power	3,834	3,759	783	8,376
Totals	**$ 91,553**	**$ 171,396**	**$ 29,403**	**$ 292,352**

AVERAGE REVENUE PER KWH

Utility	Residential	Commercial & Industrial	Other	Total
Anderson Municipal Light & Power	$0.06	$0.05	$0.20	$0.06
Auburn Municipal Electric	$0.04	$0.05	NA	$0.05
Bargersville Municipal Power & Light	$0.06	$0.06	$0.11	$0.07
Columbia City Municipal Electric	$0.06	$0.06	$0.09	$0.06
Crawfordsville Municipal Electric Light & Power	$0.07	$0.05	$0.10	$0.05
Edinburgh Municipal Electric	$0.06	$0.05	$0.07	$0.05
Frankfort City Light & Power	$0.06	$0.04	$0.08	$0.05
Garrett Municipal Electric	$0.08	NA	NA	$0.08
Kingsford Heights Municipal Electric	$0.05	NA	NA	$0.08
Knightstown Municipal Electric	$0.06	$0.06	NA	$0.06
Lawrenceburg Municipal Electric	$0.05	$0.05	$0.12	$0.05
Lebanon Municipal Electric	$0.06	$0.05	$0.10	$0.05
Logansport Municipal Electric	$0.06	$0.05	$0.11	$0.05
Mishawaka Municipal Electric	$0.06	$0.06	$0.09	$0.06
Paoli Municipal Electric	$0.02	NA	NA	$0.06
Peru Municipal Electric Light & Power	$0.06	$0.05	$0.05	$0.05
Richmond Municipal Power & Light	$0.06	$0.04	$0.03	$0.04
South Whitley Municipal Electric	$0.03	NA	NA	$0.06
Straughn Municipal Electric	$0.05	NA	NA	$0.06
Tipton Municipal Electric	$0.06	$0.05	$0.12	$0.05
Troy Municipal Electric	$0.03	NA	NA	$0.08
Washington City Municipal Light & Power	$0.06	$0.05	$0.09	$0.05

Note: “NA”, or Not Available, because the utility did not file this information with the Commission in their annual report filing.

RETAIL MARKET SHARE

Utility	Residential	Commercial & Industrial	Other
Anderson Municipal Light & Power	49.45%	48.26%	2.29%
Auburn Municipal Electric	10.98%	86.98%	2.04%
Bargersville Municipal Power & Light	61.31%	32.34%	6.32%
Columbia City Municipal Electric	33.91%	60.86%	5.21%
Crawfordsville Municipal Electric Light & Power	22.70%	67.31%	10.00%
Edinburgh Municipal Electric	25.49%	72.86%	1.65%
Frankfort City Light & Power	28.01%	70.56%	1.43%
Garrett Municipal Electric	99.36%	NA	0.62%
Kingsford Heights Municipal Electric	58.55%	25.66%	15.79%
Knightstown Municipal Electric	52.85%	42.54%	4.61%
Lawrenceburg Municipal Electric	22.00%	75.18%	2.82%
Lebanon Municipal Electric	36.13%	60.85%	3.01%
Logansport Municipal Electric	30.76%	67.68%	1.55%
Mishawaka Municipal Electric	33.03%	60.07%	6.90%
Paoli Municipal Electric	36.01%	57.40%	6.55%
Peru Municipal Electric Light & Power	44.07%	54.03%	1.9%
Richmond Municipal Power & Light	18.25%	50.63%	31.12%
South Whitley Municipal Electric	44.06%	47.28%	8.66%
Straughn Municipal Electric	82.83%	5.05%	13.13%
Tipton Municipal Electric	36.15%	62.17%	1.68%
Troy Municipal Electric	37.89%	57.59%	4.66%
Washington City Municipal Light & Power	45.77%	44.88%	9.35%

Generation Capacity By Utility (MW)

Utility	Summer
Indiana Michigan Power Company	5,044
Indianapolis Power & Light Company	3,252
Northern Indiana Public Service Company	2,890
PSI Energy, Inc.	7,070
Southern Indiana Gas & Electric Company	1,351
Hoosier Energy	1,018
Wabash Valley Power Association	313
Indiana Municipal Power Agency	601

Source: Responses to the 2004 IURC Annual Summer Capacity Surveys

Average Revenue per kWh by State (ranked from highest to lowest)

STATE	2001	2001	2002	2002	2003	2003
	Residential	Average	Residential	Average	Residential	Average
Alaska	12.1	10.5	12.05	10.46	11.47	14.77
Hawaii	16	13.7	15.63	13.39	16.35	14.25
California	12.2	11.4	12.9	12.5	12.24	11.22
Vermont	12.5	10.8	12.78	10.87	12.36	10.94
New Hampshire	12.5	11	11.77	10.49	11.65	10.55
New York	13.9	10.9	13.58	11.29	12.89	10.46
Maine	12.9	10.1	11.98	11.36	12.89	9.78
Connecticut	10.9	9.6	10.96	9.73	10.53	9.49
Massachusetts	12.3	10.9	10.97	10.19	10.61	9.44
Rhode Island	12.1	10.9	10.21	9.19	10.5	9.36
New Jersey	10.3	9.4	10.38	9.31	9.75	8.77
Nevada	9	7.8	9.43	8.42	9.49	8.24
Pennsylvania	9.5	7.8	9.71	8.01	8.95	7.84
Florida	8.6	7.7	8.16	7.31	8.11	7.4
Illinois	8.7	6.8	8.39	6.97	7.5	6.87
Michigan	8.4	7.1	8.28	6.92	8.31	6.86
New Mexico	8.7	7	8.5	6.73	8.36	6.84
Texas	8.8	7.4	8.05	6.62	7.83	6.83
North Carolina	8.1	6.7	8.19	6.74	7.84	6.66
Arizona	8.3	7.2	8.27	7.21	7.36	6.58
District of Columbia	7.9	7.2	7.82	7.37	7.48	6.57
Delaware	8.6	6.6	8.7	7.05	7.72	6.51
Ohio	8.3	6.7	8.29	6.66	7.44	6.42
Wisconsin	7.9	6.1	8.18	6.28	8.1	6.34
Colorado	7.5	6	7.37	6	7.58	6.34
Oregon	6.5	5.7	7.12	6.32	6.96	6.34
Mississippi	7.4	6.3	7.28	6.24	6.94	6.28
Georgia	7.9	6.5	7.63	6.24	7.18	6.17
South Dakota	7.5	6.4	7.4	6.26	6.96	6.15
Kansas	7.7	6.3	7.67	6.31	7.16	6.14
Virginia	7.7	6.1	7.79	6.23	7.14	6.12
Montana	6.8	6.1	7.23	5.75	7.07	6.02
Louisiana	7.9	6.9	7.1	5.99	6.75	5.96
South Carolina	7.7	5.8	7.72	5.83	7.48	5.95
Idaho	6.1	5	6.59	5.58	6.62	5.87
Washington	6	5.6	6.29	5.8	6.15	5.83
Iowa	8.4	6.1	8.35	6.01	7.73	5.79
Tennessee	6.4	5.7	6.41	5.72	6.29	5.78
Alabama	7.1	5.6	7.12	5.71	6.8	5.74

STATE	2001	2001	2002	2002	2003	2003
	Residential	Average	Residential	Average	Residential	Average
Oklahoma	7.2	6	6.73	5.59	6.37	5.65
Minnesota	7.6	6	7.49	5.84	7.17	5.64
Maryland	7.7	6.5	7.71	6.21	6.7	5.55
Arkansas	7.7	6	7.25	5.61	6.64	5.42
Indiana	**6.9**	**5.3**	**6.91**	**5.34**	**6.49**	**5.3**
Missouri	7	6.1	7.06	6.09	6.01	5.29
North Dakota	6.5	5.5	6.39	5.45	5.85	5.24
West Virginia	6.2	5.1	6.23	5.11	6.01	5.11
Nebraska	6.5	5.3	6.73	5.55	5.83	5.09
Utah	6.7	5.2	6.79	5.39	6.56	5.09
Wyoming	6.6	4.4	6.97	4.68	6.59	4.66
Kentucky	5.5	4.2	5.65	4.26	5.41	4.22
U.S. Average	**8.57**	**7.26**	**8.46**	**7.21**	**7.99**	**7.02**

Sources: Energy Information Administration: "Electric Sales and Revenue 2002 Spreadsheets" (Table 1d) and "Electric Monthly Power" (Table 5.6 B).

IV. GLOSSARY

Affiliate: A company, partnership or other entity with a corporate structure that includes a utility engaging in or arranging for an unregulated retail sale of gas or electric energy or related services.

Capacity: The size of a plant (not its output). Electric utilities measure size in kilowatts or megawatts and gas utilities measure size in cubic feet of delivery capability.

Cooperative: A business entity similar to a corporation, except that ownership is vested in members rather than stockholders and benefits are in the form of products or services rather than profits.

Distribution: The component of a gas or electric system that delivers gas or electricity from the transmission component of the system to the end-user. Usually the energy has been altered from a high pressure or voltage level at the transmission level to a level that is usable by the consumer. Distribution is also used to describe the facilities used in this process.

Generation: The process of producing electricity. Also refers to the assets used to produce electricity for transmission and distribution.

Grandfathered Agreements (GFAs): Transmission service agreements currently in force in the MISO region that were entered into prior to September 16, 1998

Holding Company: A corporate structure where one company holds the stock (ownership) of one or more other companies but does not directly engage in the operation of any of its business.

Independent Power Producer (IPP): An independent power producer generates power that is purchased by an electric utility for resale to the end use customer or the wholesale market.

Independent System Operator (ISO): An independent organization or institution that controls the transmission system in a particular region. The ISO would have no corporate relationship with the transmission-owning utilities, and therefore would be able to assure fair and comparable access to the transmission system for all users.

Kilowatt (kW): A basic unit of measurement; 1kW = 1,000 watts.

Kilowatt-Hour (kWh): One kilowatt of power supplied to or taken from an electric circuit steadily for one hour.

Megawatt (MW): One thousand kilowatts or one million watts.

Megawatt-Hour (MWh): One megawatt of power supplied to or taken from an electric circuit steadily for one hour.

Midwest Market Initiative (MMI): In December 2002, the Midwest ISO announced the Midwest Market Initiative. The MMI refers to the preparation and implementation of the Midwest ISO wholesale energy market in the Midwest with a target launch date of March 2005.

The MMI involves the formation of real time and day ahead markets for trading electricity based on hourly locational marginal pricing.

Municipal Utility: A utility that is owned and operated by a municipal government. These utilities are organized as nonprofit local government agencies and pay no taxes or dividends; they raise capital through the issuance of tax-free bonds.

Organization of Midwest ISO States ("OMS"): A group of state utility commissions in the MISO footprint that initiated the formation of the country's first so-called regional state committee. The OMS will act as an adviser on some MISO functions and attempt to plan transmission investments on a regional, rather than state-specific basis.

Reactive Power: The portion of electricity that establishes and sustains the electric and magnetic fields of alternating-current equipment. Reactive power must be supplied to most types of magnetic equipment, such as motors and transformers. It also must supply the reactive losses on transmission facilities. Reactive power is provided by generators, synchronous condensers, or electrostatic equipment such as capacitors and directly influences electric system voltage. It is usually expressed in kilovars (kvar) or megavars (Mvar).

Reliability: A term used in both the electric and gas industry to describe the utility's ability to provide uninterrupted service of gas or electricity. Reliability of service can be compromised at any level of service: generation or production, transmission or distribution.

Service Territory: Under the current regulatory environment, an electric utility is granted a franchise to provide energy to a specified geographical territory, designated as a service territory.

State Estimator: A sophisticated mathematical "what if" simulator that allows operators and engineers to evaluate the health of the power system every few minutes by simulating the grid's response to hypothetical equipment failures.

Transmission: The process of transferring energy (either gas or electricity) from the production or generation source to the point of distribution. Also refers to the facilities used for this process.

Vegetation Management: The removal of trees and/or other vegetation, or preventing vegetative growth, for the purpose of maintaining safe conditions around energized facilities and maintaining reliable electric service. Vegetation management options include biological, chemical, cultural, manual and mechanical methods of controlling vegetation in order to prevent hazards caused by the encroachment of vegetation on facilities, and to provide utility access to the facilities.

Voltage: the rate at which energy is drawn from a source that produces a flow of electricity in a circuit; expressed in volts.

V. LIST OF ACRONYMNS

AEP	American Electric Power
APCO	Appalachian Power Company, subsidiary of AEP
BTU	British Thermal Unit
CAC	Citizens Action Coalition
CNUC	CN Utility Consulting
CSPCO	Columbus and Southern Power Company, subsidiary of AEP
CT	Combustion Turbine
EPA	Environmental Protection Agency
FAC	Fuel Adjustment Cost Charge
FERC	Federal Energy Regulatory Commission
GFAs	Grandfathered Agreements
IDEM	Indiana Department of Environmental Management
IIG	Indiana Industrial Group
I&M	Indiana Michigan Power Company, subsidiary of AEP
IMPA	Indiana Municipal Power Agency
IOU	Investor-owned Utility
IPL	Indianapolis Power and Light
ISO	Independent System Operator
ITC	Independent Transmission Company
IURC	Indiana Utility Regulatory Commission
JOA	Joint Operating Agreement
JTS	Joint Transmission System
KPCO	Kentucky Power Company, subsidiary of AEP
LMP	Locational Marginal Pricing
MMI	Midwest Market Initiative
MW	Megawatt
MWH	Megawatt Hour
MISO	Midwest Independent Transmission System Operator
NO_x	Nitrogen Oxides
NIPSCO	Northern Indiana Public Service Company
NOPR	Notice of Proposed Rulemaking
OMS	Organization of Midwest ISO States
OUCC	Office of Utility Consumer Counselor
OPCO	Ohio Power Company, subsidiary of AEP
PSI	PSI Energy

REMC	Rural Electric Membership Cooperative
RTO	Regional Transmission Organization
SCR	Selective Catalytic Reduction
SNCR	Selective Non-Catalytic Reduction
SIGECO	Southern Indiana Gas & Electric Company
SMD	Standard Market Design
SO_2	Sulfur Dioxide
WVPA	Wabash Valley Power Association